Proceedings World Geothermal Congress 2015
Melbourne, Australia, 19-25 April 2015

Key Performance Indicators for Pumped Well Geothermal Power Generation

Aaron Hochwimmer, Luis Urzua, Greg Ussher, Cameron Parker

Jacobs, PO Box 9806, Newmarket 1149, Auckland, New Zealand

aaron.hochwimmer@jacobs.com

Keywords: power generation, pumped production, economic assessment, low enthalpy, binary plant

ABSTRACT

Line shaft or electrical submersible down-hole pumps can be used to pump hot fluid from geothermal aquifers to generate electricity. The potential geothermal settings for this development approach include hot sedimentary or naturally fractured aquifers in a range of non-volcanic settings and lateral outflows of higher temperature geothermal systems in volcanic terrains. Although technically feasible, and proven in a number of fields around the world, specific project commercial viability depends on a number of geothermal resource, economic, and project development factors.

These key performance indicators are inter-related and a favourable combination may be attractive relative to the local off-take power price. These projects can be comparable to higher enthalpy conventional geothermal generation (deep self discharging wells supplying condensing steam turbine, binary, or combined cycle plant) in favorable conditions.

Numerical models representing the reservoir characteristics, engineering processes of pumped flow in wells, fluid flow in surface gathering systems, and electrical power generation are presented. In conjunction with this a financial analysis has been undertaken to illustrate the sensitivity of the key performance indicators on project return on investment. Project development risks and how these developments can be staged to reduce risk are discussed and compared to conventional geothermal generation (deep self discharging wells supplying condensing steam turbine, binary or combined cycle plant) options in several regional settings. A prospective list of locations where these project developments may be economically viable is presented.

1. INTRODUCTION

While there has been considerable amount of knowledge accumulated regarding what makes high temperature geothermal systems (with self-discharging wells) viable, there is in general less understanding of the key factors that are necessary to make lower temperature projects using pumped wells commercially attractive. A few countries with high feed in tariffs have attracted recent developments targeting deep aquifers and associated new research, but otherwise much of the knowledge of these systems has been learned on a small number of projects in the western USA. Our experience on a range of these projects has pointed to several factors being necessary to achieve commercially viable pumped geothermal projects.

The analysis and modelling that is the main subject of this paper was initially focused on demonstrating that lower temperature outflows from high temperature systems may be development targets that are usually ignored by developers focused on the large developments possible from high temperature systems. A model for a modest scale of development is tested using a variety of parameters around an ideal, but realistic, base case that was devised using parameters seen in typical geothermal outflows in volcanic systems. However, we consider that the prospect for lower temperature developments may have some wider application, and hence present our analysis of relatively shallow developments tapping high permeability aquifers as stimulation for consideration of areas where suitable conditions for these pumped systems may be developed.

1.1 Downhole Pumps

Down-hole pumping technology can be used in geothermal power generation applications for relatively low temperature wells (<240°C). The geothermal fluid is pumped from production wells along surface pipes to a power plant. Thermal energy is converted into electrical power, normally using an Organic Rankine Cycle (ORC) power plant, and the cooled fluid is discharged back into the reservoir. A cascaded direct heating application can also be considered, as Combined Heat and Power (CHP), to recover additional low grade heat prior to re-injection. Additional injection pumping may be required depending on the capacity of injection wells and the surface discharge pressure provided by the down-hole pumps.

There are two main types of downhole pumps currently used: lineshaft vertical turbine pumps (LSP) and electrical submersible pumps (ESP).

With an ESP, the motor is located down-hole below the pump and is exposed to the temperature of the fluid. Power is supplied via a specially protected cable from the surface. A variable speed drive is often used to provide flow control. The pump discharges into a ‘riser’ pipeline within the well casing which brings the fluid to the surface. ESPs have had wide-spread use in the petroleum industry. While less prevalent in geothermal fields they have been used in fields such as Soultz EGS Pilot Plant (France), the Steamboat II and III sites (USA) and at Unterhaching and Dürrnhaar (Germany). The maximum motor working temperature claimed by ESP vendors is around 250°C, but given the need to dissipate heat from the motor using the production fluid as coolant, the practical limits for production fluid temperature is much lower. Higher temperature fluid reduces the potential pump power rating and ESP have not yet proven long operating life at higher end temperatures (>160°C).

In contrast a LSP consists of a surface vertical shaft electric motor, and down-hole pump driven by a line-shaft that runs inside the pump delivery pipe inserted down the well. An oil lubrication system is required to lubricate the shaft bearings. Downhole LSPs have been used over the last 30 years in the USA for geothermal applications. They have been derived from water well pumps. The first application was in the East Mesa field (California) in the 1970s. LSPs must be installed in relatively vertical wells, with 13-3/8” primary production casing, and are limited to depths of approximately 730m with operational field experience to about 215°C (Frost, 2010).

Pump reliability is of particular focus in these applications. LSPs typically last for 1-3 years (refurbishment through to full replacement), but may last longer depending on the operating conditions and environment. Vendor claims of five years mean time run to failure are typical for ESPs. However, pump operating performance in the field can be significantly less depending on the operating environment, with temperature, chemistry, and pump speed being key resource factors. In some fields sand and gravel from the formation have negatively impacted pump reliability. Experience with large capacity pumps in geothermal applications suggest a run life in the order of 1-2 years, although this is expected to improve as additional operational experience is obtained and improvements made through vendor research and development if the market for pumps remains large enough to support vendor research efforts.

1.2 Geothermal Settings for Pumped Developments

The potential geothermal settings for this development approach include hot sedimentary or naturally fractured aquifers in a range of non-volcanic settings and lateral outflows of higher temperature geothermal systems in volcanic terrains. Enhanced geothermal systems (EGS) projects have also employed down-hole pumps, of both types (Genter, et. al. (2010)).

1.2.1 Hot Sedimentary Aquifers (HSA) Setting

Some large and deep sedimentary basins have been successfully developed both as stand-alone power generation projects and as CHP.

The East Mesa geothermal power facility lies a few miles east of El Centro in southern California’s Imperial Valley. The project was built in stages during the 1980’s and is probably one of the longest running “hot sedimentary aquifer” type systems in the world. Its moderate/high-temperature (149 to 191°C) resource is associated with the tectonic environment of the Salton Trough but the reservoir is hosted in sediments comprising river deposited sands with high porosity interbedded with low permeability silts. The reservoir production zone is between 600-1,850m.

All production wells at East Mesa are pumped, with pump replacements required every 24 months or so. There are 4 ORC power plants operating from the East Mesa resource, with a capacity of 22 MW_e (net), 10 MW_e (net), 12 MW_e (net), and 18 MW_e (net) respectively. The reservoir has seen pressure decline in production wells because injection has been mainly placed at shallow levels which are vertically isolated from the deeper production reservoir, but otherwise has secured good long term production.

There are about a total of 100 production and injection wells drilled in the field and about 50% of those wells are currently used. The pumps used in this project are line shaft pumps with motors above ground and failures are generally due to wear from the sand that is drawn slowly though the system.

Naturally fractured crystalline reservoirs in the USA have also been developed (for example Combs et. al. (2011)) using pumped production to depths of 2-3 km. These are ‘pseudo-sedimentary’ in nature but exhibit sufficient fracturing and inter-well permeability to allow sufficient ‘heat-sweep’ for power production.

In the USA basin systems have been examined by others (Allis et. al. (2013)) suggesting that in the local power market temperatures of more than 175 °C, at depths of less than 4 km are required for project viability.

The southern German Mollasse Basin supports a number of smaller projects drilled in the 3-4.5km depth range, utilizing an extensive karstified and faulted limestone reservoir. This reservoir exhibits good permeability and fluid can be produced at around 140°C with manageable parasitic (pump power) losses. Projects are in various stages of completion in locations south of Munich (Sauerlach, Kirchstockach, Dürrnhaar, and Unterhaching). The electricity market in Germany has a high feed-in tariff for geothermal power and is different in this context to most of the world, and has a critical influence on project viability as might be expected.

In Australia hot sedimentary aquifer type developments have also been considered in the Great Artesian Basin in the 2-3 km depth range, but to date have not found sufficient permeability to justify large up-scaling of early testing.

Experience from these applications indicates the importance of both reservoir and near well permeability. In particular near-well permeability is a key parameter as it directly influences the parasitic power requirements for pumping at commercial flow rates. Near-well permeability directly affects wellbore fluid level drawdown under pumping conditions and hence the fluid lifting that is required to be delivered by the downhole pumps. If permeability is low, then the power required for pumping can exceed that generated from the produced fluids. In some settings wells have been completed with multiple legs, or forked completion, to achieve the required well productivity at reasonable pumping power loads.

1.2.2 Volcanic Setting

Conventional high temperature (volcanic hosted) liquid dominated geothermal systems typically have a convective upflow, outflow and recharge process as idealized in Figure 1 which shows a high-relief hydrothermal system in a mature volcanic (andesitic) setting.

The topography of these systems, coupled with the presence of unconsolidated volcanics sequences with high permeability in the upper 1000m of many of these volcanic complexes can enable the development of hydrothermal outflows with productive moderate temperature reservoirs (> 160°C) that are at least partly isolated from the deeper high temperature reservoir(s). Lateral outflow zones of hot liquid water, often with temperature reversals beneath are found in many high temperature fields. In some cases these outflows are extensive with prolific flow rates (e.g. Ramirez et. al. 2009).

In a similar way to the operating HSA projects these outflows can be developed for power generation. In certain situations this type of development can be attractive compared to conventional deep drilling and steam flash condensing plant. The depths for drilling are expected to be shallower than those required for HSA projects, which in turn reduces cost of drilling and improves project economic viability.

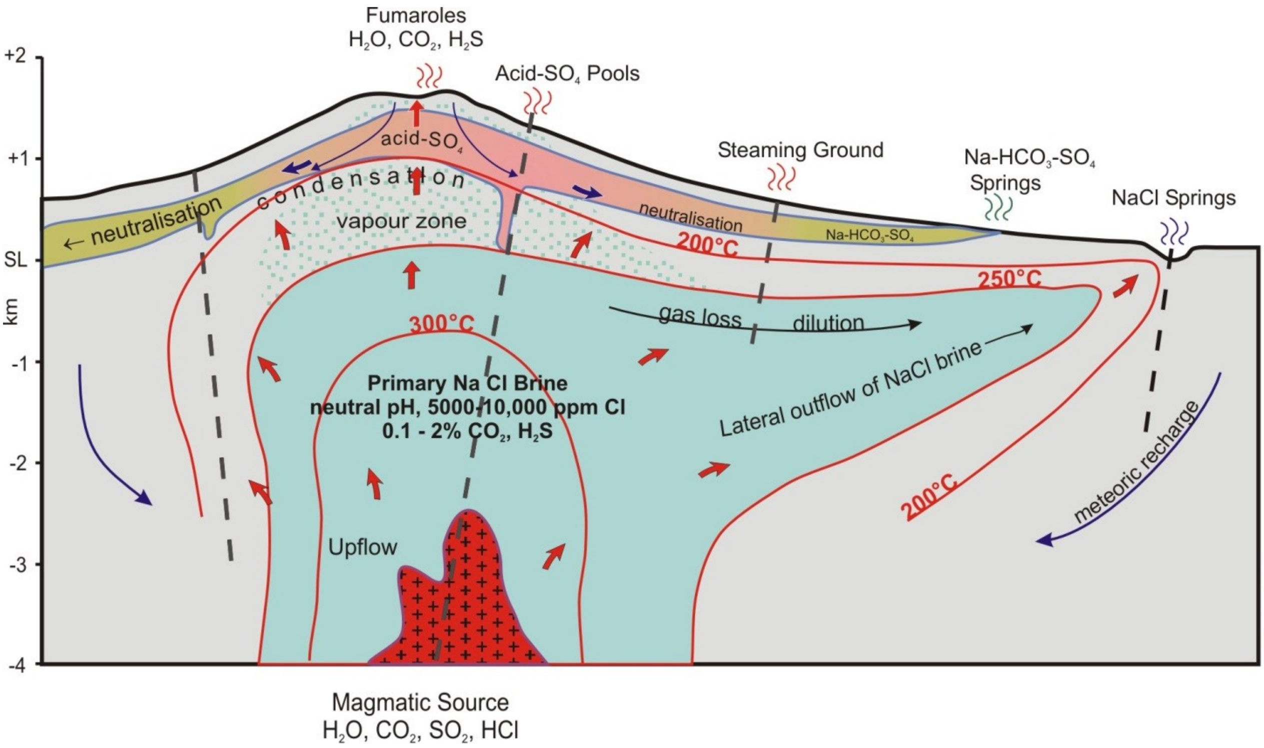

Figure 1: Conceptual Model Schematic for a Liquid Dominated Geothermal System in a High-Relief Volcanic Setting

2. MODEL DESCRIPTION

2.1. Model Overview

A Microsoft Excel based hydraulic pumped well and power plant model has been developed and used as technical inputs to a financial model. It represents the process in Figure 2 from the production feedzone to the injection feedzone.

For a given flow-rate and well configuration the model calculates:

- pressure drops in the system;
- required set depth of the down-hole pump;
- gross and net power at the plant;

The model can be used to establish the maximum flow rates possible within the operating limits of the pump and the specified well geometry. Previous work by others (Sanyal, et. al., 2007) discussed a limitation of 457m depth for LSPs, although it appears that more recent advances in LSPs have surpassed this earlier limitation. As operational information is obtained the model has been refined to reflect advances in pump technology and experience.

When the model results are assessed in conjunction with capital cost estimates, optimum pump types and flow rates can be determined. Application of this model is discussed in Clotworthy et. al. (2010), Groves et. al. (2012), and Hochwimmer et. al. (2013).

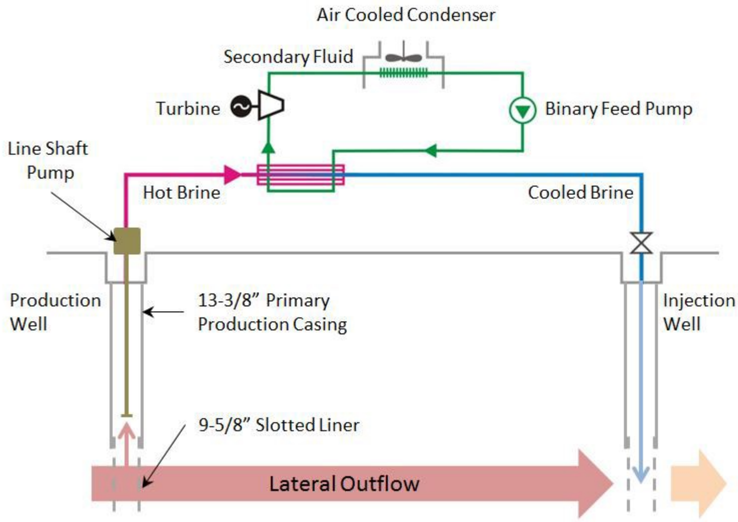

Figure 2: Schematic of a Simple Hot Water Binary ORC Power Plant, pumped from a Lateral Outflow. Figure not to scale.

2.2. Calculating Pump Set Depth and Pumping Power

The required lift is the difference between the required pressure at the wellhead and the dynamic (operating) water level in the well plus pressure losses in the vertical suction and delivery piping.

The wellhead pressure is set as a model input to overcome pressure losses in the surface piping, plant equipment, and reinjection system, prevent flashing of the fluid, and to limit deposition of mineral scale on internal surfaces of the piping system.

For a given flow rate, the dynamic water level is a function of the pressure at the well feed zone (with allowance for long term changes) and the well Productivity Index (PI), which describes the well linear draw-down under flow.

The model explicitly calculates for required minimum pump set depth, h, by first calculating the pressure drop between the primary production casing shoe and the pump impeller bowl. This pressure drop is referred to as ΔP_{c1p} in Figure 3 and is calculated as:

$$P_{c1p} = P_{res} - (Q/PI) - \Delta P_c - \Delta P_l - (P_{NPSH} + P_{sm} + P_{sat}) \qquad (1)$$

The variables in (1) are defined as:

- P_{res} = static reservoir pressure
- Q = pumped mass flow rate
- PI = well productivity index
- ΔP_c = hydrostatic and frictional pressure drop in secondary casing strings (if any)
- ΔP_l = hydrostatic and frictional pressure drop in liner sections or in open hole
- P_{NPSH} = required pump net positive suction head (NPSH)
- P_{sm} = additional safety margin to avoid cavitation
- P_{sat} = fluid saturation pressure at production temperature

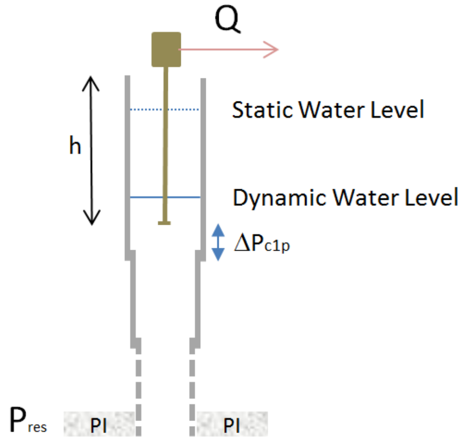

Figure 3: Schematic of pumped well under flowing conditions showing pump set depth (h). Figure not to scale.

The flow into the well is assumed to be governed by Darcy's law and can be expressed as a linear drawdown relationship:

$$Q = PI\ (P_{res} - P_{wf}) \qquad (2)$$

where:

- P_{wf} = flowing wellbore pressure

The required set depth of the pump is then calculated as:

$$h = z_{c1} - \Delta P_{c1}p\ /\ (\rho g + 2\rho f U^2/D) \qquad (3)$$

where:

- z_{c1} = vertical depth of primary production casing shoe
- ρ = fluid density
- g = gravitation acceleration
- f = Moody friction factor
- U = fluid velocity
- D = primary production casing inner diameter

The required discharge pressure of the pump is calculated as the sum of the required production wellhead pressure (WHP) plus hydrostatic and frictional pressure drop in the pump riser.

$$P_{dis} = WHP + (\rho g h + 2\rho h f U^2/D) \qquad (4)$$

The required hydraulic pump power is then:

$$E_h = (P_{dis} - (P_{res} - (Q/PI) - \Delta P_{c1p} - \Delta P_c - \Delta P_l))\ (Q/\rho) \qquad (5)$$

And the required pump shaft power is:

$$Es = Eh/\eta_{pump} \qquad (6)$$

Where η_{pump} is overall pump efficiency and includes electrical losses in the motor. The pump stage efficiency is in of the order of 68-78% however, once efficiency losses in power cables and other electrical losses are considered, a lower a figure of 65% is more conservative, and it is the one we used in this model. Injection pump parasitic losses are calculated in a similar way but consider the injection WHP required to inject the fluid.

2.3. Estimating Power Plant Efficiency

Tester et. al. (2006) presented a correlation for ORC cycle net thermal efficiency as a function of geothermal fluid.

$\eta_{net} = (0.0935T_{res} - 2.3266)/100$ (7)

Equation (7) is based on ten existing binary plants across a range of geothermal fluid temperatures. This equation gives reasonable results however the ambient dry bulb temperature does have a significant impact on efficiency particularly in hot conditions.

Refined estimates can be made by considering a process model of the cycle that examines the performance of individual items of equipment.

2.4. Calculating Financial Parameters

A simple discounted cash flow model has been used to account for capital and operating cost estimates over a 25 year period. Cash flow calculations incorporate cost estimates at ± 40% accuracy and discounted at a post-tax nominal rate of 10%. For the avoidance of doubt, this level of cost estimate is not suitable for investment decision purposes.

The power plant asset is depreciated using straight line depreciation at 4% over the life of the asset. Funding is assumed to be equity only, meaning zero debt financing in the first instance, and taxable earnings face a corporate tax rate of 30%. Inflation has been applied to all costs and revenues at a rate of 2%.

An adjusted debt to equity ratio of 70% debt to 30% equity was also tested. This assumed a loan life of 10 years at an interest rate of 8% per annum.

3. KEY PERFORMANCE INDICATORS

There are a number of key performance indicators that are useful to consider development of pumped systems across all geothermal settings:

- Depth to drill to intersect target formation
- Temperature of the target formation
- Well productivity and injectivity
- Reservoir permeability
- Reservoir capacity (aerial extent)
- Pump reliability
- Project development size
- Capital cost of wells, plant, fluid conveyancing system, and pumps
- Local power price

The combination of temperature and well productivity in particular will determine the net power output per well. For a given development size this will dictate the number of wells required, and in turn the associated surface fluid gathering and reinjection system.

Well productivity can be influenced by the impact of neighboring wells, and appropriate consideration for well spacing is necessary to minimize interference. In addition the risk of temperature interference, that is premature cooling of production wells through rapid return of injection fluid, needs to be considered for a particular setting.

Outside of the technical/economic KPIs environmental and cultural factors must also be holistically assessed.

3.1 Deterministic Assessment

Assessment is undertaken based on the technical inputs provided in Table 1. This represents a nominal 20MW$_e$ (net) development size comprising of 6 production wells and 3 injection wells tapping a shallow lateral outflow. Well costs reflect large bore (13-3/8") primary production casing to 300m with 9-5/8" slotted liner to target depth.

The power plant capital cost is dependent on factors such as brine temperature, size of plant, and market competition. It has been estimated as a function of gross output and has considered existing published information on similar equipment procured using an Engineer-Procurement-Construction (EPC) contracting model.

The power plant component is about 70% of the capital cost for the assumptions in Table 1 because very shallow wells are assumed tapping the outflow structures. Deeper systems would face greater costs but possibly lower cost per depth than high temperature wells because of the reduced safety margins needed at lower temperatures.

Table 1: Assumptions (Base Case)

Parameter	Unit	Value
Depth to Drill	m	350
Temperature	ºC	200
Plant Rejection Temperature	ºC	70
Productivity Index (PI)	t/hr.b	25
Injectivity Index (II)	t/hr.b	25
Production Wells	-	6
Injection Wells	-	3
Total Brine Mass Flow Rate	kg/s	282

Gross Power	MW_e	26.40
Net Power (excl. pumps)	MW_e	23.37
Net Power (incl. pumps)	MW_e	22.35
Well Cost	USD	800k
Pump Cost	USD	550k
Pump MTBF	Years	3
Piping Cost per "Dimension Inch Foot"	USD/DIF	20
Plant Cost (Air Cooled Binary)	USD	48M (factored price by net MW)

Variation on the base case scenario is focused on brine resource temperature (Figure 4), pump mean time between failure (Figure 5), well productivity index (Figure 6), and well depth (Figure 7). In the analysis the flow rate per well was adjusted, where required, so that the pump operating condition was still achievable with commercial available pumps. For instance in the lower PI cases, the flow was reduced to ensure the pump set depth and parasitic load were realistic.

Levelised electricity/energy cost (LEC) results for a 100% equity financing model are shown alongside a 70% debt to 30% equity ratio. This is to illustrate the sensitivity of financing structure on project economics. The effect of 70% debt in project financing is a reduction in LEC by up to 20%. This is due to the applied discount rate reducing from 10% to approximately 7% when the assumed debt is factored in.

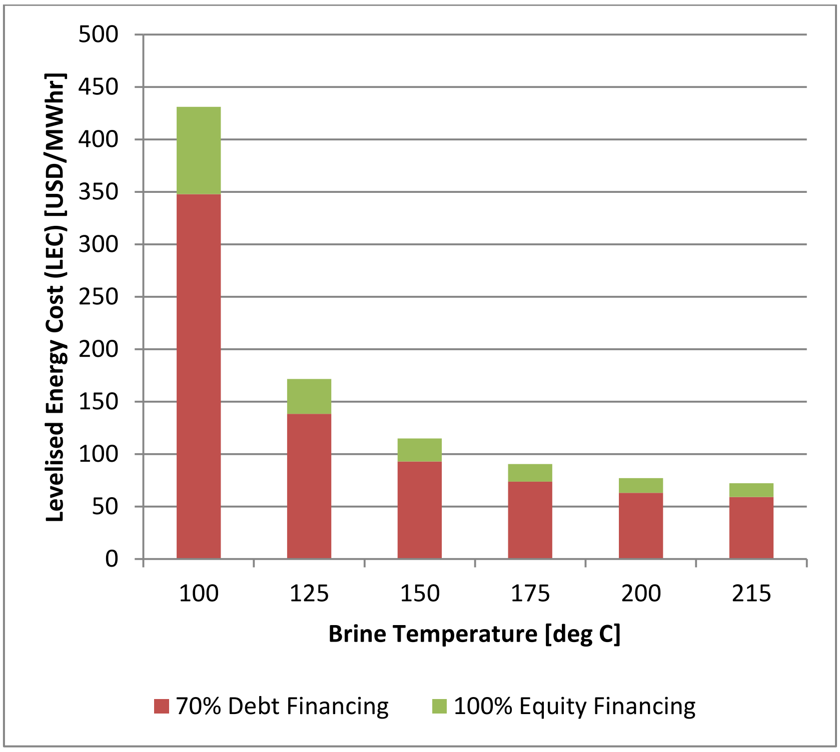

Figure 4: Sensitivity of LEC to Brine Resource Temperature (relative to base case assumptions)

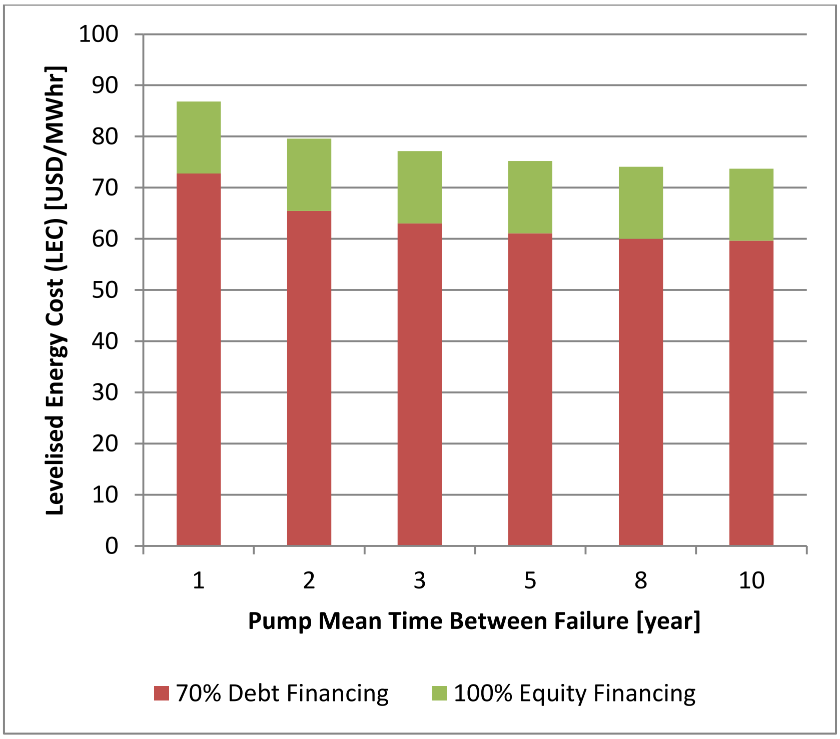

Figure 5: Sensitivity of LEC to Pump Mean Time Between Failure (relative to base case assumptions)

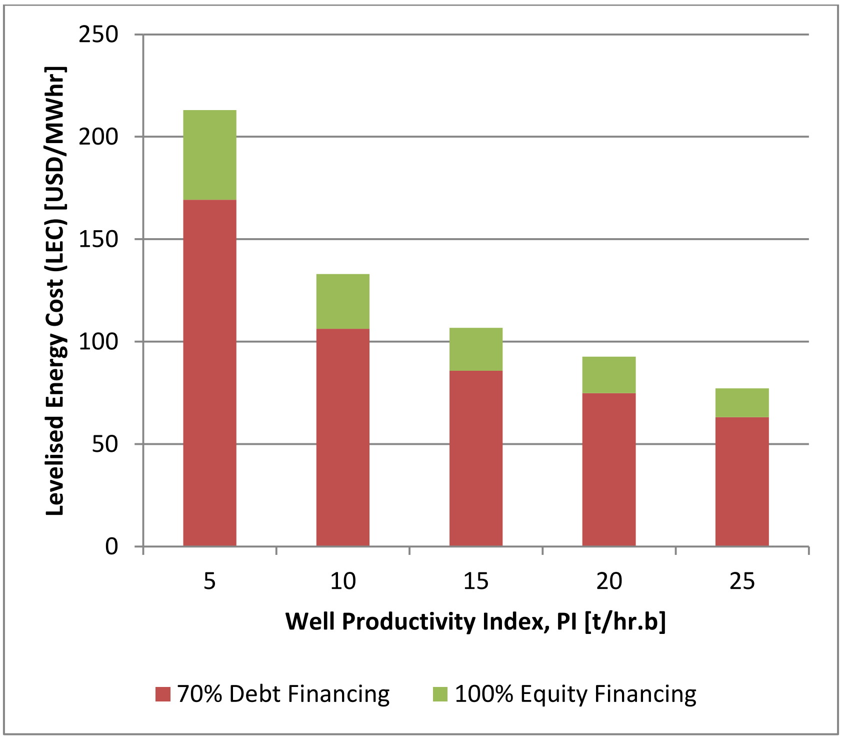

Figure 6: Sensitivity of LEC to Well Productivity Index (relative to base case assumptions)

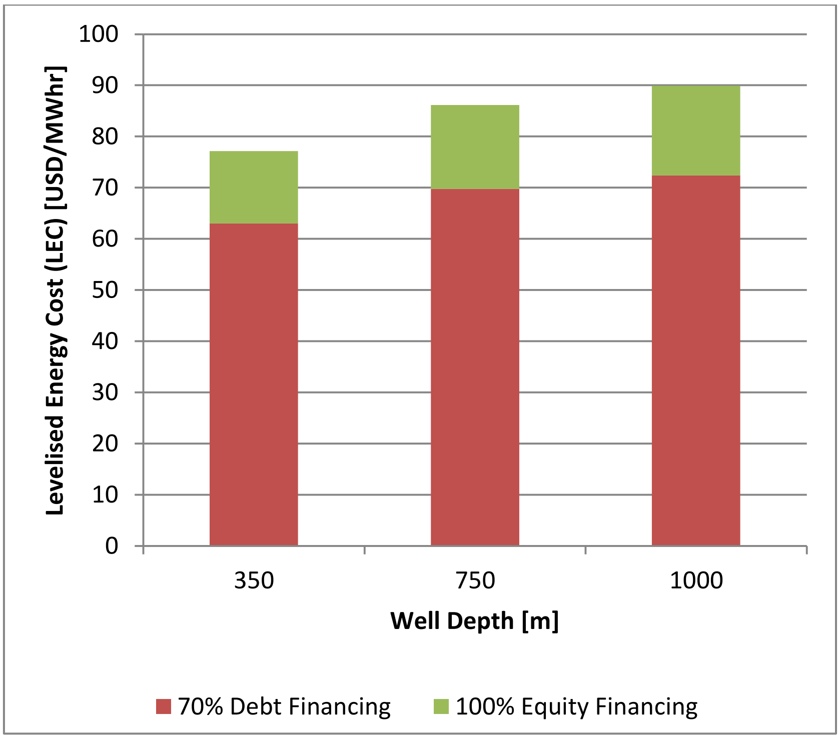

Figure 7: Sensitivity of LEC to Well Depth (relative to base case assumptions)

In the sensitivity analysis the mass flow has been held constant within the operating constraints of the pumps. There is potential for further optimization of the pump performance in some situations. For instance the pump can be set deeper (in deeper wells) and can realize higher flow-rates at the expense of additional parasitic load.

The fundamental consideration in pumped systems - in all settings - is achieving commercial flow rates with sufficient temperature and at manageable parasitic loads. Determining the optimum involves a balance of flows from production and injection wells through consideration of interplay of the key performance indicators.

The results indicate most sensitivity to resource temperature and well productivity. Well productivity directly influences the flow rate that can be achieved per well for available pumps. Temperature directly influences gross power and also energy conversion efficiency in the power plant. The higher the temperature (within pumping limits) and the higher the productivity the lower the levilised electricity cost.

Pump reliability is somewhat less sensitive at replacement intervals over 1-2 years. For a specific project the sensitivity to well depth and cost will depend on the size of the development, and the relative proportion of well and pump cost relative to the overall capital expenditure. There is also a balance of flow (and parasitic load) per well compared to the number of wells to achieve fuel supply to the power plant.

In practice the economics can be very sensitive to depth. Drilling cost increases with depth. Temperature generally increases with depth, excepting the outflow case which may exhibit temperature inversion immediately below the outflow zones. In most settings reservoir permeability decreases with depth and so the analysis should consider an appropriate range of inputs for these inter-related performance indicators.

Other workers (e.g. Sanyal et. al. 2009) have examined sensitivity of pumped systems for deeper non-convective sedimentary reservoirs. This work also identified for a given depth, the lower the resource temperature the higher the sensitivity to PI.

Outflow systems in particular represent a context for pumped systems where a number of the key performance indicators are all favorable, that is a positive convergence of shallow wells, high PI, and sufficiently high temperature.

3.2 Probabilistic Assessment

Clotworthy et. al. (2010) presented a probabilistic model for pumped production in a HSA setting. This work assumed a maximum available pump pressure, given other parameters, and probabilistic inputs for formation permeability, thickness, pressure and temperature. Flow was calculated at the point where drawdown in the formation equals the available head from the pump, and is implicitly a function of reservoir properties. A vertical well configuration was assumed consisting of 13-3/8” casing down to 2500m and a 9-5/8” liner of length 800 m, for a total well depth of 3300 m. Sensitivity of well depth (and cost) on project economics was not considered. Pump reliability was embedded in the overall operations and maintenance allowance.

That work indicated the most significant parameters were mean flow, resource temperature, and to a lesser extent plant rejection temperature. Additional probabilistic modelling explicitly considering the sensitivity of key performance indicators identified here has not been undertaken but has been identified as future work.

3.3 Project Development Considerations

Each geothermal field should be assessed on a case-by-case basis and consider the long-term behaviour of the resource (either hot sedimentary aquifer or outflow). The drilling configuration should achieve a balance between the required depth of primary production casing to set a down-hole pump, intersecting the target formations, and the cost of drilling.

The production WHP should be set above the saturation pressure of the fluid. This is to ensure the geothermal fluid is kept in liquid phase, to avoid energy loss through flashing (latent heat of vaporization) and also to avoid any operational issues with scaling (such as calcite scaling in the well).

Pumped systems require adequate pressure support to ensure that draw-down in production wells is managed. High levels of draw-down will require pumps to be set deeper with higher parasitic load requirements. The majority of pressure support for outflow systems will be from the lateral outflow itself, with some secondary pressure support from the injection wells. A reservoir engineering/modelling assessment should be done on any prospective opportunity. This will inform the spacing of production and injection wells and flow rates/well to provide a sustainable development scheme matched to the extent and flow-rate of the outflow.

This type of project development is anticipated to provide 100% re-injection of fluid back in to shallow aquifers albeit at cooler temperatures. The environmental and community impact on surface features, such as springs, downstream of the fluid take and re-injection should be investigated and understood as part of any development, and appropriate mitigation options considered at an early stage.

In high-relief volcanic settings a pumped out-flow development can offer additional advantages over a conventional development. These include:

- access to a geothermal resource in gentler lower elevation areas where outflows are often found
- reduced geohazard (volcanic and landslide) exposure to surface facilities
- reduced infrastructure construction costs

The down-hole pumps represent the highest equipment risk for these projects, in particular the risk of premature failure.

High well permeability is required to ensure that the pumps can operate within recognized power ranges and operating conditions for the expected temperature. Pump failure has been problematic in some settings, mechanisms including failure of the pump itself, motor-lead extension (for ESPs), bearings, and shaft couplings (for LSPs). Scale build-up within pumps can lead to mechanical damage of the pump and shaft, this can be managed through a chemical treatment regime. High permeability and the ability to operate the pump within its operating limits are expected to contribute to improved reliability and reduced failure.

4. PROSPECTIVE SETTINGS

Potential geothermal development utilising down-hole pumps could target naturally permeable aquifers in a range of non-volcanic and volcanic settings. This may include the outflows of high temperature geothermal systems in volcanic terrains or lower temperature systems that feed into suitable shallow and permeable aquifers that can be drilled economically. Although these types of project are technically feasible, and proven in a number of fields around the world, the commercialization of a specific project will depend on a number of factors, such as, quality of the geothermal resource, power price, community issues, access and other project development factors. A favorable combination of the key performance indicators (in particular depth, permeability and temperature) can make the economics of a low enthalpy projects or the outflow of a high enthalpy project comparable to the development of a higher enthalpy conventional geothermal generation scheme.

Table 2 lists countries known to have both a good number of high enthalpy geothermal fields (steep terrain models) and also a number of low enthalpy fields. The table also indicates the wholesale power prices for each country. Despite the high power prices in countries such as Chile, Peru, Ecuador, Colombia and Guatemala, geothermal development of low temperature is limited or non-existent. . In these countries, geothermal exploration and geothermal developments have been focused on the development of high enthalpy resources which are usually limited by the high cost of the initial exploration phase. Honduras which only has low enthalpy geothermal resources, has been progressively exploring the available resources and is now progressing development of several systems using low enthalpy production.

Relative to the benchmark power price listed in this paper, the development of high enthalpy and low enthalpy fields in these localities could be very attractive. In addition, in most of these countries low enthalpy fields have not been studied or explored since the current exploration activities are focused on conventional high enthalpy resources. At the power prices listed below, low enthalpy development may become a valid economic option and in certain cases could be represent a more convenient option than developing a high enthalpy field, particularly considering terrain access and environmental issues targeting projects in mountain areas. Commonly low enthalpy developments occur in locations where site access, connection points and community issues are less sensitive issues.

Particularly attractive are countries where power supply is based on diesel as their wholesale power prices are the highest. Based on this power price consideration the Pacific Islands and Caribbean nations may be attractive exploration and development destinations for this technology. The replacement of diesel generation could also be attractive in mining developments located in remote areas but close to geothermal fields (Peru, Chile, Andes ranges). Usually these operations utilize diesel as their main power supply. Low enthalpy developments or pumped production could represent a cost reduction to these operations reducing the reliance on the high cost associated with diesel consumption

Projects should be considered where the levelised cost of energy is below the indicative local power prices, with sufficient internal rate of return for the developer.

Table 2: Indicative Power Prices

Country	US cents/kWh	Source
Chile	23.11	"Energy Supply Pricing for Clients Subject to Price Regulation". Chilectra. Jan 1, 2011. Retrieved Feb 10, 2011.
Peru	10.44	Pliegos tarifarios de Lima-OSINERGMIN/GART, 2007
Colombia	18.05	TARIFAS DE ENERGÍA ELÉCTRICA ($/kWh) REGULADAS POR LA COMISIÓN DE REGULACIÓN DE ENERGÍAY GAS (CREG) JULIO DE 2013". Codensa. Jun 1, 2013. Retrieved Jun 31, 2013.
Indonesia	8.75	
Turkey	12.57	http://www.tedas.gov.tr/BilgiBankasi/Sayfalar/ElektrikTarifeleri.aspx TEDAS, 2014
Nicaragua	18.3	CEPAL -Precios Energia CA, 2010
Guatemala	22.1	CEPAL -Precios Energia CA, 2010
Honduras	15.2	CEPAL -Precios Energia CA, 2010
Costa Rica	17.0	CEPAL -Precios Energia CA, 2010
El Salvador	17.9	CEPAL -Precios Energia CA, 2010
Mexico	19.28	CFE 2012
New Zealand	7.2	NZ Electricity Authority (North Island only average 2011-2014)
Fiji, Vanuatu, Dominica, Grenada, St. Kitts and Nevis, St Lucia, St Vincent and the Grenadines	30-40	

5. CONCLUSIONS

Pumped systems can be economically attractive with a combination of favourable technical parameters (i.e. productivity, shallow and cheap wells and hotter temperatures) and economic parameters (i.e. tax rates, discount rates, debt/equity ratio) including power sales prices or feed in tariffs.

Particularly attractive are countries with higher power price due to high cost of alternative generation (such as diesel in isolated countries) or where renewable energy attracts feed-in tariffs. Based on power price considerations the Pacific Islands and Caribbean nations are some of the most attractive exploration and development destinations for lower temperature geothermal. The replacement of diesel generation could also be considered as an attractive alternative in remote mining operations located close to geothermal fields (Peru, Chile, Andes ranges). These mines commonly use diesel as their main power supply thus low enthalpy developments using pumped production could represent a major cost reduction to their operations. Many of the countries of Central America also have a high dependence on high fuel cost generation and with plentiful geothermal resources also present low temperature geothermal development opportunities.

In settings of outflow from high temperature systems, development can be relatively low risk when compared to deep geothermal exploration. These types of development can be explored cheaply through a combination of geo-scientific surveys and shallow drilling. In high-relief volcanic settings developing an outflow presents advantages over a conventional geothermal development in terms of road access, reduced geohazard exposure, reduced construction costs and often reduced environmental issues associated with elevated terrain areas. For a well characterised brown-field project, the outflow of the field is often well-defined laterally and at depth through the early exploration, production and delineation drilling of the deep reservoir. Therefore, development of the outflow or shallow resource can be considered as a low risk expansion option.

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